BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2020-263-E, ORDER NO. 2021-604

AUGUST 27, 2021

IN RE: Cherokee County Cogeneration Partners, LLC, Complainant/Petitioner v. Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Defendant/Respondent	))))))	ORDER RULING ON THE ESTABLISHMENT OF A LEGALLY ENFORCEABLE OBLIGATION AND REQUIREMENT OF ACCOUNTING PROCEEDING

I. INTRODUCTION

Cherokee County Cogeneration Partners, LLC (Cherokee) contends Duke Energy Progress, LLC (DEP) and Duke Energy Carolinas, LLC (DEC), Defendants/Respondents, failed to negotiate with Cherokee in good faith towards a power purchase agreement (PPA) contrary to state and federal law. Cherokee asks the Commission to resolve the parties' unresolved issues regarding a PPA to succeed the parties' current agreement, which expires on August 28, 2021. The Commission concludes the record supports a finding Cherokee established a legally enforceable obligation with DEC on September 17, 2018, pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA) and Federal Energy Regulatory Commission (FERC) implementing regulations, and establishes a plan to determine and return any overpayment of rates to consumers affected by this docket.

II. FACTS AND PROCEDURAL HISTORY

In 1995 Cherokee was granted a certificate of environmental compatibility and public convenience and necessity from the Commission due to the nature of Cherokee's hydrocarbon processing operations. Cherokee first entered into a power purchase agreement (PPA) with Duke Power Company dated August 26, 1994. At that time Cherokee planned to build a "natural-gas-fueled combined-cycle electric cogeneration facility in the vicinity of Gaffney, South Carolina." (Order No.1995-26, p. 2). Cherokee obtained certification from the FERC as a qualifying facility, with "an installed generating capacity of approximately 80 megawatts." (*Id.* p.3). The Commission approved the PPA between Cherokee and Duke with an initial term of fifteen years.[1] In that order, the Commission noted a concern inherent in setting the avoided cost component of a PPA, especially one with a lengthy term: "While Duke's more recently forecasted avoided cost estimates are lower than the avoided costs incorporated in the rates and charges of the Agreement, the Commission recognizes the limitation on the accuracy of avoided cost estimates over the terms of [PPA]s." (*Id.* p. 7).

In 2012, by Directive Order No. 2012-743, the Commission accepted a subsequent PPA between DEC and Cherokee in Docket No. 2012-272-E. The term of that 2012 PPA was July 1, 2013, to December 31, 2020. The terms of a successor PPA to that 2012 PPA is the subject of Cherokee's complaint.

[1] Commission Order No. 1995-26 states "[t]he Purchased Power Agreement dated August 26, 1994, between Cherokee County Cogeneration Corporation and Duke Power Company be, and hereby is, approved." Order 1995-26, pp. 8-9, ¶ 1.

The record reveals Cherokee and DEC began communications in mid-2018 regarding a successor PPA to the 2012 PPA set to expire on December 31, 2020. After an in-person visit and related communications, Cherokee sent a letter to DEC on September 17, 2018, stating it would obligate all its energy and capacity to DEC in a successor contract: "Pursuant to PURPA and its implementing regulations, Cherokee establishes the avoided cost for its energy and capacity as of today, September 17, 2018, the date that the LEO [legally enforceable obligation] is incurred. *See* 18 C.F.R. § 292.304(d)(2)(ii) (providing an unqualified right for QFs to establish avoided costs calculated at the time the LEO obligation is incurred)." Cherokee also sent a Notice of Commitment form (NOC), although the form Cherokee used was criticized by DEC.

In response to Cherokee's September 17, 2018 letter and NOC, DEC denied the letter established a LEO, but indicated it would offer Cherokee a "must take" agreement, in contrast to the 2012 PPA which was a dispatchable tolling agreement, at its avoided costs rates. Cherokee asserted it was unable to verify DEC's calculations of avoided costs. In the hope of making an agreement with Duke, Cherokee also sent a letter obligating itself to provide its full energy and capacity to DEP in December of 2020. DEP responded as DEC had, denying a LEO was established. Thereafter, the parties continued to communicate, but did not enter into a successor PPA.

On November 2, 2020, Cherokee filed a Complaint with the Commission asserting bad faith on the part of DEC and DEP, seeking Commission action to resolve the gridlock regarding a successor PPA, and requesting interim relief to extend the soon to expire 2012 PPA. The Office of Regulatory Staff filed a notice of appearance on November 4, 2020, asserting its status as a party pursuant to section 58-4-10 of the South Carolina Code of Laws.

The Commission heard oral argument in the docket on December 10, 2020. Cherokee asserted "[t]he parties have had a relationship for 22 years," and Cherokee wanted to continue to sell to DEC, but the negotiations "were not fruitful," and that it "was baffled" by the information received from DEC, contending it asked on "multiple occasions" for "specific backup or assumptions or . . . the underlying data that undergirded these . . . proposed . . . rates, terms, and conditions." (December 10, 2020 Hearing, Tr. p. 16, lines 2-3, p. 17, lines 17, 20-21, p. 31, lines 16-20). Cherokee also noted it was "connected to a facility called Reddy Ice, . . . to whom we provide steam that is used in that ice-making facility," and which employs "some 70 people," who would be impacted by its agreement with DEC. (December 10, 2020 Hearing, Tr. p. 13, lines 14-17, p. 24, line 20).

After oral argument the Commission issued Directive Order No. 2020-846 on December 30, 2020, granting Cherokee's request for an extension of the 2012 PPA for 120 days—until April 30, 2021—and directing the parties to conclude any mediation or discovery during that time. The Commission retained jurisdiction to "consider whether or not it is appropriate to subject the rates charged and/or paid by any Party during this 120-day period to true-up." (Directive Order No. 2020-846).

On April 14, 2021, in Directive Order No. 2021-259, the Commission adopted a procedural schedule for pre-filed testimony and exhibits for the hearing. Thereafter, on April 28, 2021, in Directive Order No. 2021-298, the Commission approved an additional extension of the term of the 2012 PPA to August 28, 2021. The Commission again retained jurisdiction to review any overage in payments since January 1, 2021, stating "Cherokee should bear the economic risk of any possible overpayment from any extension of the 2012 PPA." (Directive Order No. 2021-298).

The Commission held a hearing virtually on July 26, July 29, and July 30, 2021. Representing Cherokee were John J. Pringle, Jr., Esquire, Jenna L. McGrath, Esquire, admitted *pro hac vice*, and William DeGrandis, Esquire, also admitted *pro hac vice*. Representing DEC and DEP were Heather Shirley Smith, Esquire, (replacing Rebecca J. Dulin), Frank R. Ellerbe, III, Esquire, Edward Breitschwerdt, Esquire, admitted *pro hac vice*, and Tracy S. DeMarco, Esquire, admitted *pro hac vice* as well. Jenny R. Pittman, Esquire, and Jeffrey M. Nelson, Esquire, appeared on behalf of ORS.

After the hearing, DEC and DEP submitted a late-filed exhibit on August 4, 2021, corrected on August 6, 2021, as requested by the Commission. On August 12, 2021, Cherokee filed comments to the late-filed exhibit. DEC and DEP, on August 18, 2021, moved to strike portions of Cherokee's comments, contending Cherokee inappropriately "introduced new unverified quasi-testimony and evidence into the proceeding." (Motion, p. 10). Cherokee responded on August 24, 2021, asserting it had "responded appropriately" to the "new evidence" contained in the late-filed exhibit of DEC and DEP. (Response, p. 6).

On August 13, 2021, all parties, including ORS, filed briefs on the law. On August 20, 2021, Cherokee, and DEC and DEP jointly, submitted proposed orders.

III. EVIDENCE OF RECORD

The Commission heard testimony and accepted into the record the direct and rebuttal testimonies and exhibits of Nathan Hanson and Kurt Strunk on behalf of Cherokee. Mr. Hanson is the Senior Vice President of both Cherokee County Cogeneration Partners and LS Power, stating his role with LS Power is to "oversee the energy and commercial arrangements which ensure smooth and cost[-]efficient operations of the firm's assets across its portfolio." (Tr. p. 15.1, lines 5-11). Mr. Hanson also explained, "with respect to Cherokee, I lead a team that manages Cherokee's commercial arrangements and relationships with [DEC and DEP]." (*Id.*, lines 11-13). Hanson noted Cherokee "is fully dispatchable by DEC whenever it wants to utilize it, which enhances DEC's reliability as compared to many other Qualifying Facilities in DEC's territory, which have non-dispatchable variable outputs, such as solar facilities." (Tr. 15.10, lines 12-15). Hanson explained the importance to Cherokee of capacity payments: "Capacity payments are important for Cherokee because they provide a baseline predictable income stream for Cherokee regardless of DEC's decision to dispatch the facility. Capacity payments allow Cherokee to budget for staff, maintenance, capital investments and other needs necessary to ensure that Cherokee actually maintains the capability to run at any given time and respond to dispatch instructions from DEC." Hanson testified Cherokee established a LEO with DEC on September 17, 2018, with its Notice and its cover letter. (Tr. 15.12, lines 8-14). Hanson noted DEC's October 31, 2018 response did not include a payment for capacity and was "contingent on Cherokee executing a PPA within an arbitrary amount of time, introducing a 'shot clock,' take it or leave it element to the offer." (Tr. p. 15.13, lines 15-21).

Regarding Cherokee's letter of obligation to sell its energy and capacity to DEP on December 12, 2018, Hanson testified: "Cherokee is indifferent to whether or not it provides energy and capacity to DEC, DEP, or both companies," noting the Duke companies "touted the interconnected DEC and DEP systems that operate on an integrated, jointly dispatched basis." (Tr. p. 15.14, line 19 to p. 15.5, line 3). Hanson also stated Duke did not provide the information Cherokee needed to negotiate a PPA: "Cherokee is not in the position to determine whether any proposed rate actually reflects avoided costs, absent review of the inputs, assumptions, and calculations that resulted in that proposed rate. Absent access to the requested data, which Duke refused to provide, Cherokee has not been able to conduct meaningful negotiations regarding a new PPA." (Tr. p. 15.20, lines 14-23). Hanson testified that only after Cherokee filed its complaint did Duke provide additional information: "Duke only recently provided more detailed information in response to a data request as part of this process, which Cherokee is currently reviewing." (Tr. p. 15.22, lines 13-14). Hanson offered three exhibits, which were accepted into the record, including correspondence from Cherokee to DEC dated September 17, 2018, which Cherokee asserts establishes a LEO. (Tr. p. 15.26-27).

Expert witness Kurt G. Strunk also testified on behalf of Cherokee. Mr. Strunk is employed as the managing director of National Economic Research Associates. (Tr. p. 122, lines 14-15). Strunk criticized the response of DEC to Cherokee's offer to sell power because it did not include compensation for DEC's avoided capacity costs, citing DEC's

2018 IRP which identified upgrades and additions to two locations in its portfolio. (Tr .p. 126.13, line10, through p. 126.14, line 20). Furthermore, Strunk noted DEC was offering at that time "compensation to [other] QFs for both avoided energy cost *and* avoided capacity cost" in its "standard offer." (Tr. p. 126.14, line 25 through p. 126.15, line 2). Strunk asserted because Cherokee did not provide intermittent power, but rather able to provide power that is "fully dispatchable by Duke," Duke's decision not to provide an avoided capacity cost component to Cherokee was "discriminatory." (Tr. p. 126.15, lines 2-7). Strunk determined "$110/kW-year" would be a "fair and reasonable rate" based on DEC's avoided cost "forecasts" pursuant to a more appropriate dispatchable tolling agreement. (Tr. p. 126.18, lines 21-24). Strunk also offered into evidence his *curriculum vitae* and an appendix explaining his calculations. (Tr. p. 127, lines 11-17).

Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, entered into evidence the testimony of four witnesses: Michael Keen, John Freund, Glen Snider, and Kendal Bowman. Mr. Keen also provided exhibits in addition to his testimony.

Keen, "employed by Duke Energy as a business development manager," stated he was responsible for negotiating power purchase agreements for both DEC and DEP as well as Duke Energy Florida. (Tr. p. 240, line 24 through p. 241, line 3). Of the negotiations he engaged in with Cherokee on behalf of Duke he testified: "Put simply, Cherokee demanded, and still demands, to be paid prices for its capacity and energy that are inconsistent with PURPA . . . and that are far in excess of the Companies' actual avoided costs and what is just and reasonable for our customers to pay." (Tr. p. 242.5, lines 4-8). He went on to note the cost of energy "significantly declined over the past decade, triggering a similar reduction in the Companies' avoided costs" and that "DEC does not have an immediate need for additional capacity to serve its customers beginning in 2021." (*Id.*, lines 9-12). Keen opined: "the Cherokee Facility seemingly requires rates two to three times in excess of the Companies' avoided cost rates to be profitable." (*Id.*, lines 12-14).

Keen recalled receiving a letter and Notice of Commitment (NOC) letter from Cherokee on September 17, 2018, but testified he disputed Cherokee established a LEO, stating Cherokee's NOC was one used for qualifying facilities generating two megawatts of energy or less, unlike Cherokee. (Tr. p. 242.11, line 8-13). Keen formally responded to Cherokee on October 31, 2018, offering a five-year agreement with calculated avoided costs rates, but not a capacity component "because DEC's then-current integrated resource plan . . . did not identify a capacity need until 2028." (Tr. p. 242.12, lines 3-8). Keen also testified its original response to Cherokee was a "must-take, non-dispatchable PPA as that is the standard Commission-approved structure offered to large QFs," but that in September 2020, DEC offered a dispatchable tolling agreement "in a good faith attempt to reach a resolution between the parties." (Tr. p. 242.20, lines 4-5, 8-10). Keen testified Duke also modified its original response by offering a PPA to Cherokee with a ten-year term. (Tr. p. 242.19, line 20).

Keen further testified he responded to Cherokee promptly during their negotiations "while disputing the establishment of a LEO," and contended Cherokee "stalled the negotiations at several junctures." (Tr. p. 242.21, lines 14-17, 20). Keen stated ultimately "the negotiations with Cherokee failed because Cherokee was unwilling to accept rates that reflected the Companies' avoided costs. . . . Because PURPA prohibits utilities from paying rates above their avoided costs, the Companies have no flexibility to provide Cherokee the significantly higher avoided cost rates that Cherokee is seeking." (Tr. p. 242.22, lines 6-7, 10-12). Keen entered three exhibits to his direct testimony which were accepted into the record. (Tr. p. 243).

Witness John Freund, a senior structuring analyst employed by Duke Energy provided avoided cost calculations and methodology support for the company. (Tr. p. 336, lines 10-16). He explained DEC calculated avoided cost rates for Cherokee five times between October 2018 and February 2021. (Tr. p. 338.4, lines 6-8). Freund submitted the chart below to summarize DEC's and DEP's contract proposals:

Freund Direct Figure 1:
Five Avoided Cost Rate Proposals Provided to Cherokee

	DEC Oct. 2018	DEP Feb. 2019	DEP Jun. 2020	DEC Sept. 2020	DEC Feb. 2021
Date of rate request	9/17/18	12/12/18	5/4/20	9/17/20[1]	n/a[2]
Date rate provided	10/31/18	2/1/19	6/24/20	9/17/20[3]	2/10/21
PPA structure	Non-dispatchable	Non-dispatchable	Non-dispatchable	Dispatchable tolling	Dispatchable tolling
IRP used to support first year of capacity need	2018 IRP (DEC)	2018 IRP (DEP)	2019 IRP (DEP)	2020 IRP (DEC)	2020 IRP (DEC)
First year of capacity need based on IRP	2028	2020	2020	2026	2026
Timing of gas cost assumptions	September 2018	December 2018	April 2020	April 2020	August 2020
Term	5 years	5 years	5 years	10 years	10 years

[1] Occurred during the 9/17/20 telephone conversation between Cherokee Witness Hanson and DEC/DEP Witness Keen.

[2] As discussed by Witness Keen, the rates provided by DEC to Cherokee in February 2021 represented DEC's effort in anticipation of the February 2021 mitigation to reach agreement with Cherokee.

[3] Occurred during the 9/17/20 telephone conversation between Cherokee Witness Hanson and DEC/DEP Witness Keen.

(Tr. p. 338.5, lines 1-4, with footnotes).

As to Cherokee's assertion Duke did not provide sufficient information for it to verify how Duke calculated its rates, Freund testified: "[t]he Companies provided similar levels of rate support to Cherokee as to other larger QFs. Outside of a formal regulatory proceeding, our practice has generally been to respond to large QFs' questions verbally, and/or to provide examples and summary level numerical information." (Tr. p. 338.10, lines 18-21). Of Cherokee witness Strunk's calculations of what Duke's avoided cost rates should have been, Freund responded: "Witness Strunk attempted to convert the fixed dollars per MWh energy pricing included in the rates DEC provided to Cherokee on October 31, 2018[,] into a payment structure comparable to the 2012 dispatchable tolling PPA." (Tr. p. 338.11, lines 17-19). Freund went on to explain several reasons Strunk's calculations were "inappropriate" and "greatly over-simplify the determination of an avoided cost rate." (Tr. p. 338.12, lines 5, 9). "Reducing Witness Strunk's total avoided cost rate of $110/kW-year by $20/kW-year to account for costs DEC would incur for start cost related payments to Cherokee, and by $32/kW-year to account for the years of the contract in which DEC would have no avoidable capacity need, results in a total rate of $58/kW-year[.]" (Tr. p. 338.14, lines 15-18). Freund went on to add, however, this rate remained "inappropriate" because DEC "disagrees that Cherokee is entitled to 2018 avoided costs," asserting a LEO did not exist. (Tr. p. 338.14, line 19 through p. 338.15, line 2).

Glen A. Snider, Director of Carolinas Integrated Resource Planning and Analytics for Duke testified regarding Duke's IRPs, asserting he is familiar with PURPA and FERC regulations, although he is not an attorney. (Tr. p. 390.2, lines 3-12, 19-22, Tr. p. 390.5, line 9). Snider noted: "From a resource planning perspective, the utility cannot rely upon the QF to deliver capacity and energy over a future term to serve customers unless and until the QF signs a new PPA committing itself to do so." (Tr. p. 390.10, lines 13-15). Snider stated he did not believe Cherokee established a LEO with DEC on September 17, 2018, because Cherokee used a NOC form "only applicable to small standard offer QFs of 2 MW or less," and which expressly stated it "terminates if the Seller (Cherokee) does not execute a PPA 30 days after the Company delivers an executable PPA." (Tr. p. 390.14, lines 4-5, 11-13). Snider also asserted that "Cherokee's actions during the 2018-2020 time frame make clear that it did not commit its output to either DEC or DEP." (*Id.*, lines 17-19). Snider stated Cherokee rejected Duke's rates and requested rates above Duke's avoided costs. (Tr. p. 390.15, lines 20-22). Snider also explained the peaker methodology Duke used to determine avoided cost rates. (Tr. pp. 390.17-390.21). To illustrate his opinion Duke's avoided cost rates have "declined significantly since 2012," Snider offered the following figure, noting in the footnote it was developed for a North Carolina Utilities Commission docket:

Snider Direct Figure 2:[33]

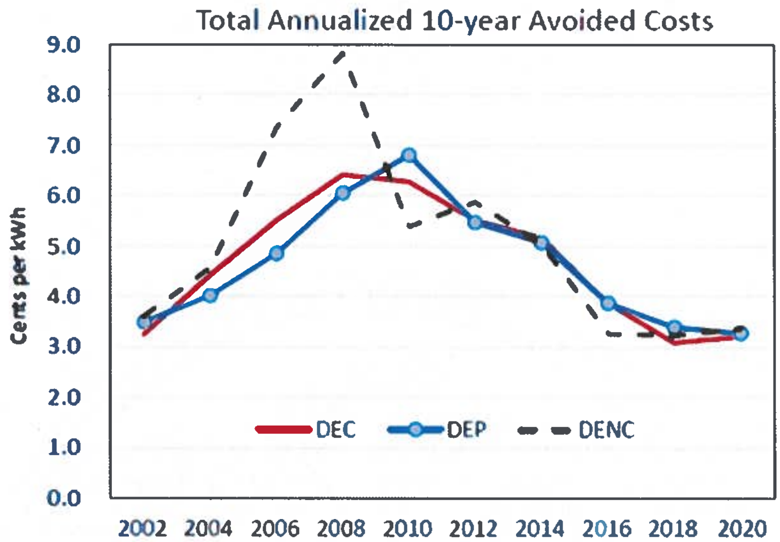

Figure 1: Total Annualized 10-year Avoided Costs (Approved and Proposed)

[33] Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2020, Initial Statement of the Public Staff – North Carolina Utilities Commission at 8, Docket No. E-100, Sub 167 (Jan. 25, 2021) (showing approved total avoided costs for DEC, DEP, and Dominion Energy North Carolina from 2002-2018 and proposed annualized avoided cost rates for 2020).

(Tr. p. 390.33, lines 9, 10, and footnote).

Duke also called Kendal C. Bowman, formerly a Duke Energy attorney and currently Vice President of Regulatory Affairs and Policy for Duke Energy North Carolina. (Tr. p. 491, lines 2-13). Ms. Bowman noted PURPA and FERC regulations mandate a utility may not pay more than its avoided costs to a QF: "[t]he intended result is that utility customers remain indifferent between the utility purchasing QF output, on the one hand, or producing the power itself or buying it from another resource, on the other hand." (Tr. p. 494, lines 11-18). She stated: "PURPA was not intended to force utilities or their customers to subsidize QFs" (Tr. p. 495, lines 1-2); but acknowledged PURPA does establish "each utility is obligated to purchase power from every QF that commits itself to sell to the utility at the utility's avoided cost." (Tr. p. 502.11, lines 4-5). Bowman went on to characterize Cherokee as a "large 98 MW cogeneration QF that exceeds the 80 MW size limit for small power producers," and thus is not eligible for "standard offer avoided cost rates." (Tr. p. 502.13, lines 13-14, Tr. p. 502.14, line 19 through p. 502.15, line 1). Of the relationship between DEC and DEP, Bowman testified: "Because DEC and DEP are each separate 'electric utilities' under PURPA, they are independently obligated to implement PURPA and purchase QF power at each utility's respective avoided costs," and denied the Joint Dispatch Agreement created a "single utility." (Tr. p. 502.16, lines 8-12).

Of the establishment of a LEO by Cherokee, Bowman stated: "based on my review of the correspondence between Cherokee and the Companies, Cherokee's actions clearly did not establish a LEO in 2018, as Cherokee never actually committed to sell its power to either DEC or DEP." (Tr. p. 502.22, line 20 through p. 502.23, line 2). She further testified: "By rejecting each of the Companies' repeated offers of avoided cost rates and PPAs and making counter offers at rates well above the Companies' avoided costs, Cherokee's claim of an LEO is inconsistent with FERC's regulations and PURPA, which limits the Companies' purchase obligations to rates set based on the utility's avoided costs." (Tr. p. 502.23, lines 6-10).

ORS called Dawn M. Hipp, Chief Operating Officer, as its witness. (Tr. p. 562, lines 5-14). Ms. Hipp provided direct testimony "limited in nature to ensure the customers of Duke Energy do not pay more than the appropriate Commission-approved avoided energy and avoided capacity costs for the power supplied by Cherokee under the terms of any successor power purchase agreement." (Tr. p. 563, lines 17-21). She noted "ORS does not engage in purchased-power contract negotiations between QFs and electric utilities" (Tr. p. 564, lines 4-5); and ORS did not become aware of the dispute in this docket until Cherokee filed a complaint with the Commission on November 2, 2020. (Tr. p. 568.4, lines 3-4). ORS's recommendation, she asserted, is that "the successor PPA between Cherokee and Duke Energy limit payments made to Cherokee for energy and capacity at or below the actual avoided costs calculated based on the methodology approved by the Commission." (Tr. p. 568.6, lines 1-3). Moreover, Hipp states ORS "recommends the dollar amount attributed to the incremental overpayment to Cherokee due to the extension of the terms of the current 2012 PPA be credited or refunded to Duke Energy customers in a manner determined by the Commission." (*Id.*, lines 13-16).

In rebuttal testimony, Cherokee witness Strunk denied he testified Cherokee "needed rates that were higher than DEC's avoided cost." (Tr. p. 598.3, lines 8-9). "My understanding is that Cherokee never sought a rate that was above reasonably forecasted avoided costs for DEC as of September 2018 when Cherokee expressed its commitment of capacity to DEC." (*Id.*, lines 12-14). To rebut Freund's criticism of his calculations, Strunk asserts he "did not need to run a production cost model" and that he "relied on the output of DEC's own production cost modeling." (Tr. p. 598.13, lines 10-16). Strunk also disagreed with Snider's avoided cost methodology noting the North Carolina Utilities Commission rejected the assumption of zero capacity credit employed by Snider as part of the peaker methodology, and therefore disputed Freund's claim DEC's October 2018 offer was 'fundamentally consistent" with [Order 2016-349, dated May 12, 2016]." (Tr. p. 598.12, line 8 through p. 598.13, line 2). Strunk stated: "It was not appropriate for DEC to prejudge the outcomes of future adjudicated proceedings and offer zero capacity compensation to DEC while offering full capacity compensation to QFs initiating standard offer contracts in late 2018." (Tr. p. 598.15, line 21 through p. 598.16, line 2).

Hanson, in rebuttal, testified: "PURPA requires that Duke offer avoided cost calculations based on projections *as of the LEO date* for the period of delivery under the contract. Contrary to the requirements of PURPA, Duke repeatedly failed to provide pricing based on the date of the LEO." (Tr. p. 660.3, lines 6-7, italics in original). Hanson noted "the formation of a LEO turns on the actions of the QF, *not* the actions of the utility." (Tr. p. 660.6, lines 1-2, italics in original). As to Duke's claim Cherokee submitted an incorrect NOC form, Hanson stated this claim "is nonsensical" because "Cherokee conveyed the necessary information to Duke in order to establish its LEO," and because Duke "never made available any 'correct' form for Cherokee to use." (*Id.*, lines 11-16). Hanson asserted Duke did not, at any time, make Cherokee an offer consistent with PURPA, and provided the following timeline of Duke's offers:

Table 1: Timeline of Offers

Date	Offered by	Deficiencies
October 31, 2018	Duke Energy Carolinas	– Did not appropriately take into account the dispatchability of the Cherokee facility. – Discriminatory; did not provide compensation for avoided capacity costs. (See Strunk Rebuttal, p.11). – Inconsistent with Order 2016-349 and FERC's Implementing Regulations. (See Strunk Rebuttal).
February 1, 2019	Duke Energy Progress	– The transmission arrangements were not offered in a manner consistent with DEC and DEP's merger commitments. – Did not appropriately take into account the dispatchability of the Cherokee facility.
June 24, 2020	Duke Energy Progress	– Included avoided cost rates, but on terms that ran contrary to those approved in Order 2020-315(A). – Offered a form PPA appropriate for a solar QF and inappropriate for a dispatchable facility like Cherokee. – Disputed the establishment of a LEO.
December 15, 2020	Duke Energy Carolinas	– Offered an "as available" contract. – Failed to provide contract rates until after the delivery of energy to Duke such that Cherokee would have no idea whether its plant would be economic to run.
February 10, 2021	Duke Energy	– Apparently took dispatchability into account, but: – Avoided energy costs were not aligned with the Cherokee LEO date. – Avoided capacity costs were not aligned with the Cherokee LEO date.

(Tr. p. 660.8)

IV. LAW

By way of introduction to the law, we note there have been significant changes to federal and state law during the course of the negotiations between the parties that is the subject of this docket. More specifically, we note at the time Cherokee asserts it established a LEO with DEC on September 17, 2018, FERC Order No. 872 had not been issued and Act 62 was not yet effective. We thus are constrained to apply the law to actions of the parties in 2018 to reach certain conclusions.

Beginning with state law, the Commission has the authority and jurisdiction to approve all contracts made by an electrical utility:

> Nor shall any contract establishing a rate or rates or any other contract affecting the use or disposition of its product or the charges to be paid therefor be entered into by any electrical utility without prior approval by the Commission . . . . Full power and authority is hereby conferred on the Commission to accomplish the purposes expressed in this section.

S.C. Code Ann. § 58-27-980 (2015).

Federal law informs the Commission regarding agreements between electric utilities and qualifying facilities from whom a utility purchases power. Title 16 of the United States Code of Laws Annotated includes statutes regarding the Federal Regulation and Development of Power in Chapter 12. That chapter declares the selling of electric energy is a matter within the public interest: "It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest . . . . " 16 U.S.C.A. § 824(a).

The federal statutes encourage cogeneration and small power facilities to produce energy, and require electric utilities to offer to purchase electric energy from those cogeneration and small power production facilities:

> (a) Cogeneration and small power production rules
> Not later than 1 year after November 9, 1978, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage

> geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to--
> (1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities[] and
> (2) purchase electric energy from such facilities.

16 U.S.C.A. § 824a-3(a).

Furthermore, the United States Code establishes a utility must purchase power from a cogeneration facility at a rate that meets the following criteria:

> (b) Rates for purchases by electric utilities
> The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase--
> (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and
> (2) shall not discriminate against qualifying cogenerators or qualifying small power producers.
>
> No such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

16 U.S.C.A. § 824a-3(b).

The Federal Energy Regulatory Commission implemented regulations regarding PURPA. Subchapter K of Title 18 of the Code of Federal Regulations contains the federal regulations undergirding PURPA. A qualifying facility is defined as "a cogeneration facility or a small power production facility that is a qualifying facility under Subpart B of this part." 18 C.F.R. § 292.101(b)(1).[2]

[2] Subpart B refers to the transmission lines and equipment a qualifying facility uses "to transmit supplementary, standby, maintenance and backup power to the qualifying facility . . . ." §292.101(b)(1)(i)(B) (2018).

Avoided costs are defined as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101 (b)(6).

The Federal Code requires utilities to purchase power from a qualifying facility in accordance with the provisions of this section:

> Each electric utility shall purchase, in accordance with § 292.304, unless exempted by § 292.309 and § 292.310, any energy and capacity which is made available from a qualifying facility:
> (1) Directly to the electric utility; or
> (2) Indirectly to the electric utility in accordance with paragraph (d) of this section.
>
> . . .
>
> If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e)(4) and shall not include any charges for transmission.

18 C.F.R. § 292.303(a) and (d)(2018).

Section 292.304 of the 2018 Code established the rates that must be used for purchases of power by utilities from qualifying cogeneration facilities:

(a) Rates for purchases.

(1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) Relationship to avoided costs.

(1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.[3]

(2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section

(3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b)(2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

[3] The Commission found Cherokee intended to construct a facility in Gaffney in its January 12, 1995 order, Order No. 1995-26, Docket No. 94-615-E. Moreover, Order No. 1995-26 also found "Cherokee has obtained FERC's determination of its status as a QF," and referenced FERC's issuance of QF status upon Cherokee on September 19, 1994. Therefore, we take judicial notice the construction of Cherokee's facility commenced after November 9, 1978.

(c) Standard rates for purchases.

(1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) Purchases "as available" or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(e) Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

§ 294.304.

The regulations also contained general rules for setting rates for the sale of power:

(a) General rules.

(1) Rates for sales:

(i) Shall be just and reasonable and in the public interest; and

> (ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.
>
> (2) Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

18 C.F.R. § 292.305 (2018).

In addition to the option for a qualifying facility to establish a legally enforceable obligation, as set forth in section 294.304, utilities and qualifying facilities may negotiate contracts and agree to rates, terms, and conditions different from those "which would otherwise be required" by this section of the Code:

> (b) Negotiated rates or terms. Nothing in this subpart:
>
> (1) Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart; or
>
> (2) Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.

18 C.F.R. § 292.301(b).

The Code established a general rule to provide how a utility must make avoided cost data available, publicly:

> (b) General rule. To make available data from which avoided costs may be derived, not later than November 1, 1980, June 30, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority,

> and shall maintain for public inspection, and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:
>
> (1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;
>
> (2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and
>
> (3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

18 C.F.R. § 292.302(b).

Furthermore, this Commission may review the utility's avoided costs rates and the utility has the burden to justify the data used to support its calculations:

> (e) State Review.
>
> (1) Any data submitted by an electric utility under this section shall be subject to review by the State regulatory authority which has ratemaking authority over such electric utility.
>
> (2) In any such review, the electric utility has the burden of coming forward with justification for its data.

18 C.F.R. § 292.302(e).

The federal regulations also provided the procedure for an electric utility to follow to end its obligation to purchase power from a QF, but only if it is "on a service territory-wide basis":

> An electric utility may file an application with the Commission for relief from the mandatory purchase requirement under § 292.303(a) pursuant to this section on a service territory-wide basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in § 292.309(a)(1), (2) or (3) have been met. After notice, including sufficient notice to potentially affected qualifying cogeneration facilities and qualifying small power production facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in § 292.309(a)(1), (2) or (3) have been met.

18 C.F.R. § 292.310 (2018).

Thus, to summarize, on September 17, 2018, the date Cherokee asserts it established a LEO with DEC, PURPA, as implemented in the Code of Federal Regulations, provided that an electric utility, such as DEC, "shall purchase, in accordance with § 292.304 . . . any energy and capacity which is made available from a qualifying facility." 18 C.F.R § 292.303(a). Furthermore, the rates must be "just and reasonable to the electric consumer of the electric utility and in the public interest," must [n]ot discriminate against qualifying cogeneration . . . . facilities; and the law does not require an electric utility "to pay more than the avoided costs" when purchasing power from a QF. 18 C.F.R. § 292.304 (2018).

Since 2018, however, there have been many changes in the law. Most notably the South Carolina Legislature enacted Act 62 and FERC issued Order No. 872.

Act 62 became effective on May 16, 2019, and its provisions were codified in the South Carolina Code of Laws, including the creation of Chapter 41 to Title 58, entitled Renewable Energy Programs. In addressing power purchase agreements between electrical utilities and small power producers in section 58-41-20, the Commission is authorized to approve "multiple form power purchase agreements to accommodate various generation technologies." § 58-41-20(A). However, the parties may choose to enter into PPAs "that differ from the [C]ommission-approved forms(s)." *Id.* In addition, "[t]he avoided cost rates offered by an electrical utility to a small power producer not eligible or the standard offer must be calculated based on the avoided cost methodology most recently approved by the commission." § 58-41-20(C). Disputes will be resolved by the Commission "in a formal complaint proceeding." *Id.* Furthermore, the small power producer can give notice to sell "at the avoided cost rates and pursuant to the power purchase agreement then in effect" by sending an executed notice:

> (D) A small power producer shall have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed notice of commitment to sell form to the electrical utility. The commission shall approve a standard notice of commitment to sell form to be used for this purpose that provides the small power producer a reasonable period of time from its submittal of the form to execute a power purchase agreement. In no event, however, shall the small power producer, as a condition of preserving the pricing and terms and conditions established by its submittal of an executed commitment to sell form to the electrical utility, be required

> to execute a power purchase agreement prior to receipt of a final interconnection agreement from the electrical utility.

Act 62 also provided electrical utilities should offer fixed price PPAs at avoided cost, for "a duration of ten years" or longer:

> (F)(1)Electrical utilities, subject to approval of the commission, shall offer to enter into fixed price power purchase agreements with small power producers for the purchase of energy and capacity at avoided cost, with commercially reasonable terms and a duration of ten years. The commission may also approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, which must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including, but not limited to, a reduction in the contract price relative to the ten year avoided cost.

In addition to the changes to the South Carolina Code resulting from Act 62 in state law, FERC significantly revised the federal regulations, based upon the issuance of Order No. 872, to balance encouraging QFs to prosper with the need to establish avoided cost rates sensitive to the rates in existence at the time.[4] As stated in the PURPA Title II Compliance Manual:

> FERC has more recently adopted in Order No. 872 significant reforms to its PURPA regulations relating to the rates at which electric utilities must purchase the output of QFs. These reforms . . . attempt to balance the statutory requirement for "encourage[ment] of cogeneration and small power production" with current market realities.

The new regulations effective as of December 31, 2020, allow this Commission more flexibility to set the rates for purchases:

[4] Order No. 872, 85 FR 54733, Sept. 2, 2020, effective as of December 31, 2020.

(d) Purchases "as available" or pursuant to a legally enforceable obligation.

(1) Each qualifying facility shall have the option either:

(i) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the electric utility's avoided cost for energy calculated at the time of delivery; or

(ii) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, except as provided in paragraph (d)(2) of this section, be based on either:

(A) The avoided costs calculated at the time of delivery; or

(B) The avoided costs calculated at the time the obligation is incurred.

(iii) The rate for delivery of energy calculated at the time the obligation is incurred may be based on estimates of the present value of the stream of revenue flows of future locational marginal prices, or Competitive Prices during the anticipated period of delivery.

(2) Notwithstanding paragraph (d)(1)(ii)(B) of this section, a state regulatory authority or nonregulated electric utility may require that rates for purchases of energy from a qualifying facility pursuant to a legally enforceable obligation vary through the life of the obligation, and be set at the electric utility's avoided cost for energy calculated at the time of delivery.

. . .

(e) Factors affecting rates for purchases.

(1) A state regulatory authority or nonregulated electric utility may establish rates for purchases of energy from a qualifying facility based on a purchasing electric utility's locational marginal price calculated by the applicable market defined in § 292.309(e), (f), or (g), or the purchasing electric utility's applicable Competitive Price. Alternatively, a state regulatory authority or nonregulated electric utility may establish rates for purchases of energy and/or capacity from a qualifying facility based on a Competitive Solicitation Price. To the extent that capacity

rates are not set pursuant to this section, capacity rates shall be set pursuant to subsection (2).

(2) To the extent that a state regulatory authority or nonregulated electric utility does not set energy and/or capacity rates pursuant to paragraph (e)(1) of this section, the following factors shall, to the extent practicable, be taken into account in determining rates for purchases from a qualifying facility:

(i) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;

(ii) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(A) The ability of the electric utility to dispatch the qualifying facility;

(B) The expected or demonstrated reliability of the qualifying facility;

(C) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(D) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the electric utility's facilities;

(E) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(F) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(G) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(iii) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2)(ii) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(iv) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of

> energy itself or purchased an equivalent amount of electric energy or capacity.
> (f) Periods during which purchases not required.
> (1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.
> (2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.
> (3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.
> (4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

18 C.F.R. § 292.304 (effective December 31, 2020, and current through August 12, 2021).

IV. ANALYSIS

This Commission has been presented with a significant challenge to resolve the issues in this docket due to the passage of time between the parties' initial communications regarding a successor PPA and today. This challenge is further exacerbated by the fact there have been changes in the law and in the price of gas during the time Cherokee and DEC have engaged in communications regarding a successor agreement. We find the parties missed a valuable opportunity to seek input from the Commission sooner.

We do not find DEC's response to Cherokee's letter of September 17, 2018, denying Cherokee established a legally enforceable obligation was appropriate. We question DEC's offer of a "must take" agreement, in light of the history between the companies and the nature of the dispatchable power Cherokee had been providing under the 2012 PPA. We recognize however DEC did provide a response to Cherokee which included avoided costs rates, albeit pursuant to a "must take" agreement. We also recognize Cherokee has attempted to choose other than avoided cost terms related to a successor PPA that spanned a number of years.

PURPA allows a QF to establish an obligation and to choose the date on which to determine avoided cost rates, either on the date of the establishment of the LEO or upon delivery of the power. The law anticipates the particular terms of a successor PPA would be determined by negotiation between parties. It is unfortunate the parties could not negotiate at that time, or prior to December 31, 2020, towards a mutually appropriate agreement, reasonable and fair to the parties and to the customers. It is also unfortunate neither party availed the matter to the Commission earlier. We are thus constrained to provide a solution to a situation which spans the course of changing markets and changing law and in which there has been a very unfortunate delay for resolution in a timely manner.

To this end, we begin by holding before us the mandate of FERC's regulations implementing PURPA:

> (1) Rates for purchases shall:
> (i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and
> (ii) Not discriminate against qualifying cogeneration and small power production facilities.

> (2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

18 C.F.R. § 294.304.

In 2018 and continuing today, PURPA and the implementing regulations provide protections for a QF. The law requires a utility to purchase the power of a QF and gives to the QF the power to choose the date on which the avoided cost rates of the utility shall be set—either the date of delivery or the date the QF obligated itself to provide the power.

In 2018, section 292.304(d) appeared in the federal code as follows:

> (d) Purchases "as available" or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:
>
> (1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or
>
> (2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> (i) The avoided costs calculated at the time of delivery; or
>
> (ii) The avoided costs calculated at the time the obligation is incurred.

We find the evidence in the record supports a determination the letter Cherokee sent to DEC on September 17, 2018, established a LEO. Cherokee wrote, in part, to DEC:

> By submitting his Notice, Cherokee is making a legally binding offer of all capacity and energy associated with the Facility to DEC as of January 1, 2021, the day after expiration of its current Power Sales Agreement between

> Cherokee and DEC . . . . ***Pursuant to PURPA and its implementing regulations, Cherokee establishes the avoided cost for its energy and capacity as of today, September 17, 2018, the date that the LEO is incurred.*** *See* 18 C.F.R. § 292.304(d)(2)(ii) (providing an unqualified right for QFs to establish avoided costs calculated at the time the LEO obligation is incurred). . . . We look forward to a productive process for negotiating and finalizing a new power purchase agreement for the Facility . . . .

Hearing Exhibit No. 1 (emphasis added).

V. FINDINGS OF FACT

After review of all of the evidence, including the testimony and exhibits of the witnesses, the Commission makes the following findings of fact:

1. Cherokee established a legally enforceable obligation (LEO) with Duke Energy Carolinas on September 17, 2018, to sell its power at Duke Energy Carolinas' avoided cost rate approved and determined by the Commission which existed on the date of the obligation.

2. Cherokee is entitled to assert its rights pursuant to the LEO it established with DEC on September 17, 2018.

3. FERC's regulations allow Cherokee to be paid either (1) the purchasing electric utility's avoided cost calculated at the time of delivery, or (2) the purchasing electric utility's avoided cost calculated at the time the LEO is incurred.

4. DEC is required under PURPA to buy power from Cherokee at its avoided cost rate calculated using the methodology approved by the Commission as of the date the legal enforceable obligation was established or as of the date of delivery of power.

5. The date that the legally enforceable obligation was established is September 17, 2018.

6. The date of delivery is January 1, 2021, when the 2012 PPA existing between the parties at the time of the legally enforceable obligation was established.

7. DEC represented to the Commission it is in agreement with Cherokee "that a 10-year dispatchable tolling agreement structure is appropriate based upon current regulatory circumstances." DEC's representation is undisputed by Cherokee. Therefore, in accepting this representation by DEC, those matters are resolved and there is no longer any need for Commission decision related to term or type of agreement. We find the utilization of a dispatchable tolling agreement is logical in this instance for many reasons including, but not limited to, the fact that: Cherokee is not a solar or wind generator QF; Cherokee already exists and is in operation; and Cherokee currently delivers power to DEC on a dispatchable basis.

8. Pursuant to Cherokee's LEO, DEC would be subject to Cherokee's choice to be paid either DEC's avoided cost calculated at the time of delivery or DEC's avoided cost calculated at the time the LEO is incurred.

9. The Commission further finds that whether Cherokee selects the date of the obligation or the date of delivery, the avoided cost rate must be based upon the avoided cost rate methodology determined and approved by the Commission and existing on September 17, 2018, or at the time of delivery, which we find would have been January 1, 2021. It is just and reasonable for the avoided cost rates to be calculated using the

Commission's approved and adopted methodologies for calculating capacity and energy avoided cost rates existing at the time.

10. As an alternative option, the Commission also finds that PURPA and Commission rules allow the parties to negotiate an agreement if Cherokee chooses not to continue to assert its rights to a LEO established on September 17, 2018.

11. In fairness to the ratepayers and in recognition of the extended term of the 2012 PPA set to expire on August 28, 2021, we find a swift resolution to this matter is in the public interest. Therefore, we find the following schedule is appropriate:

a. Within seven (7) business days from the service of the Commission's Order in this docket, Cherokee shall notify DEC in writing, and by filing to the Commission's Docket Management System, whether Cherokee chooses to assert the LEO established in September 17, 2018, and whether Cherokee chooses the avoided cost rate, using the methodology approved by the Commission, as of the date Cherokee established the LEO, or the date of delivery following its 2012 PPA term, January 1, 2021.

12. We find it is just and reasonable for Cherokee and DEC to execute any successor PPA between them (if any) on the earlier of the following two dates: no later than:

a. no later than fourteen (14) business days after Cherokee submits and files its avoided costs rate selection, or

b. no later than twenty-one (21) business days from the date of service of this Order.

13. We find it is just and reasonable for DEC to file the successor PPA with the Commission and provide a copy to the ORS in accordance with existing rules and regulations of the Commission.

14. The deadlines for resolution set forth above provide a fair and expedited procedure to a successor PPA; however, we recognize the extended 2012 PPA is set to expire on August 28, 2021 per Commission Directive Order No. 2021-294 dated April 28, 2021.

15. The Commission finds that there is insufficient information in the record to make a determination on the amount or existence of any overpayment, underpayment, or need for true up in the public's interest and that of the DEC rate payer. Therefore, the Commission requires an additional proceeding to determine any overage or underage in rates that may have resulted from extensions of the 2012 contract terms between the parties since January 1, 2021, and we retain jurisdiction of this docket for future proceedings and determinations.

16. We find it is just and reasonable to require DEC to file a petition for an accounting and true-up of rates paid from January 1, 2021 until the beginning date of the new PPA, as well as any other remedy related to an alleged discrepancy between the avoided cost rates paid by DEC to Cherokee on or after January 1, 2021, and during the extension of the 2012 PPA.

17. We find it is just and reasonable to require DEC to file this petition no later than thirty (30) days from the entry of the successor PPA with Cherokee, or within forty-five (45) days from the service of this Order, whichever occurs first.

18. We find it is appropriate to carry over the Motion to Strike filed by Duke Energy Carolina LLC, and Duke Energy Progress, LLC.

19. We further find that having found that a legally enforceable obligation exists between Cherokee and DEC, it would be moot to make any such determination related to Cherokee and DEP.

VI. CONCLUSIONS OF LAW

1. Cherokee established a legally enforceable obligation with DEC on September 17, 2018.

2. Cherokee is entitled to assert its rights a legally enforceable obligation.

3. Cherokee, as QF establishing a legally enforceable obligation, has the choice to be paid at the avoided cost rates of DEC calculated using the Commission approved methodology existing on the date the obligation incurred, or at avoided cost rates of DEC calculated using the Commission approved methodology existing at the time of delivery pursuant to 18 C.F.R. § 292.304(d).

4. In accordance with the September 17, 2018 legally enforceable obligation established by Cherokee as allowed by 18 C.F.R. § 292.304(d), DEC is subject to Cherokee's choice to be paid either using DEC's avoided cost rate methodology calculated at the time of delivery, or using DEC's avoided cost rate methodology calculated at the time the LEO is incurred.

5. If Cherokee does not choose to continue to assert its legally enforceable obligation established on September 17, 2018, the parties may negotiate an agreement pursuant to 18 C.F.R. § 292.301 and shall determine avoided cost rates using the Commission's approved and adopted methodologies for calculating capacity and energy avoided cost rates existing at the time.

6. The Commission must have sufficient and accurate information concerning any ruling on the specific dollar amount, or the existence of, any overpayment, underpayment, or need for true up in the public's interest and that of the DEC ratepayer due to the extension of the 2012 PPA after December 31, 2020. Therefore, an additional proceeding requesting an accounting to determine any overage, underage, or true up, related to payments between Cherokee and DEC that may have resulted from extensions of the 2012 contract terms between the parties since January 1, 2021; thus, the Commission retains jurisdiction of this docket to hold such matters in a future proceeding to be filed and to make such determinations.

7. We find it is appropriate, just, and reasonable to require DEC to file a petition for an accounting and true-up of rates paid from January 1, 2021 until the beginning date of the new PPA, as well as any other remedy related to an alleged discrepancy between the avoided cost rates paid by DEC to Cherokee on or after January 1, 2021, and during the extension of the 2012 PPA.

8. A further proceeding is required to determine any overage or underage that may have resulted from extensions of the 2012 contract terms since January 1, 2021, to compensate for any overage amounts customers may have made have made since January

1, 2021, in keeping with 18 C.F.R. § 292.304(a), "[r]ates for purchases shall . . . [b]e just and reasonable to the electric consumer of the electric utility and in the public interest."

VII. ORDERING PROVISIONS

IT IS THEREFORE ORDERED:

1. Cherokee is entitled to assert its rights pursuant to a legally enforceable obligation established with DEC on September 17, 2018.

2. DEC is required to purchase Cherokee's power at its avoided cost rate methodology on the date Cherokee chooses pursuant to the legally enforceable obligation it established on September 17, 2018, under 18 C.F.R. § 292.304(d), which is ether the date of the legally enforceable obligation of September 17, 2018 or the date of delivery which is January 1, 2021.

3. Whether Cherokee selects the date of the obligation or the date of delivery, the avoided cost rate shall be based upon the avoided cost rate methodology determined and approved by the Commission and existing on September 17, 2018, or at the time of delivery, which we find would have been January 1, 2021.

4. If Cherokee chooses not to continue to assert its rights to a LEO established on September 17, 2018 and the parties negotiate an agreement, the avoided cost rate shall be based upon the avoided cost rate methodology determined and approved by the Commission at the time of the execution of the agreement.

5. Within seven (7) business days from the service of the Commission's Order in this docket Cherokee shall notify DEC in writing, and by filing to the Commission's Docket Management System, whether Cherokee chooses to assert the LEO established in

September 17, 2018, and whether Cherokee chooses the avoided cost rate, using the methodology approved by the Commission, as of the date Cherokee established the LEO, or the date of delivery following its 2012 PPA term, January 1, 2021.

6. Cherokee and DEC shall execute the successor PPA between them (if any) on the earlier of the following two dates:

a. no later than fourteen (14) business days after Cherokee submits and files its avoided costs rate selection, or

b. no later than twenty-one (21) business days from the date of service of this Order.

7. DEC shall file the successor PPA with the Commission and provide a copy to the ORS in accordance with existing rules and regulations of the Commission.

8. The parties shall appear in an additional accounting proceeding to determine the specific dollar amount of any overage, underage, or true up related to any payment(s) from DEC to Cherokee after December 31, 2020 resulting from the extension of the 2012 PPA contract terms between the parties since January 1, 2021.

9. The Commission shall retain jurisdiction of this docket for future proceedings and determinations related to an accounting of the specific dollar amount, or the existence of, any overpayment, underpayment, or need for true up in the public's interest and that of the DEC ratepayer due to the extension of the 2012 PPA after December 31, 2020.

10. No later than thirty (30) days from the entry of the successor PPA between Cherokee and DEC, or no later than forty-five (45) days from the service of this Order,

whichever occurs first, DEC shall file a petition for an accounting and true-up of rates paid from January 1, 2021 until the beginning date of the new PPA, as well as any other remedy related to an alleged discrepancy between the avoided cost rates paid by DEC to Cherokee on or after January 1, 2021, and during the extension of the 2012 PPA.

11. The Commission shall address the Motion to Strike filed by Duke Energy Carolina LLC, and Duke Energy Progress, LLC, in the additional proceeding, or before.

12. This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Justin T. Williams, Chairman
Public Service Commission of
South Carolina